Volume Determination and Recoverability of Free Hydrocarbon

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Abstract

Free-phase hydrocarbon product occurs as perched zones on the capillary fringe beneath numerous petroleum-handling facilities. Under such site conditions, too much emphasis is placed on the time-frame required for remediation by federal, state, and local regulators, notably in respect to monitoring the efficiency and effectiveness of the respective remediation program. The time required for remediation within the scope of present-day technology is a calculated or educated guess at best. Typically, remediation duration is determined by a number of estimates. These estimates have innate compounding errors. Areas of estimation include physical measurement accuracy; "true" vs. apparent thickness; validity of bail-down testing; extrapolation of free hydrocarbon product thicknesses between monitoring points; contouring of thickness maps, extrapolation of geologic information, planimetering, and estimation of porosity; specific yield and retention; all of which are key factors used in ultimately determining the volume of free hydrocarbon product in place.

Once an initial estimated volume is determined, pilot testing of a recovery system should commence to determine recovery rates.

Factors that will affect recovery rates include the areal distribution and geometry of the hydrocarbon pool, type, and number of recovery system(s) selected, and the performance or efficiency of these systems with time. Effectiveness of the recovery program is thus best estimated based on barrels recovered to date divided by the total volume of barrels that are considered recoverable.

Remediation time frame at petroleum hydrocarbon recovery sites can be estimated. However, regulators at all levels need to be aware of the large number of compounding errors associated with these calculations. Estimations should be used with extreme caution, because they are usually overestimations. Once a realistic time frame for remediation is mutually agreed upon, it should be clearly understood that it is flexible. It is recommended that a range be initially determined and that as a project progresses and new data are introduced, the remediation time frame be adjusted accordingly.

Introduction

A large number of petroleum-handling sites, including petroleum refineries, are included on the U.S. Environmental Protection Agency's National Priorities List (U.S. Environmental Protection Agency 1986). In the Los Angeles Coastal Plain, for example, a minimum of 17 oil refineries and tank farms have been designated as health hazards. This designation reflects the petroleum residues from such facilities that migrate through the subsurface resulting in the presence of free-phase liquid hydrocarbon pools on the capillary fringe overlying the water table. Although several of these refineries are listed as hazardous waste sites and remediation is being promulgated under RCRA, a majority of such facilities are undergoing remediation under the California Regional Water Quality Control Board Order 85-17 adopted in February 1985. This order requires, in part, delineation of free liquid hydrocarbon pools and other ground water pollutants that may affect subsurface soils and/or ground water under such facilities, subsequent recovery of free hydrocarbon product, aquifer restoration (dissolved phases), and soil remediation (residual hydrocarbon).

Subsurface site remediation begins with delineation and estimation of the volume of free-phase liquid hydrocarbons present. Some of these free-phase hydrocarbon pools encompass tens to hundreds of acres in lateral extent and up to several hundreds of thousands of recoverable barrels in total volume. However, it is generally estimated that up to only 50 percent (although typically 20 to 30 percent) of the total pore volume of free hydrocarbon product present is recoverable by conventional means.

As part of the regulatory process, the reviewing agency requests not only information regarding lateral extent, but also evaluation of total volume of free hydrocarbon present, percent recovered to date if recovery has been in progress for some time and the overall time frame for complete recovery of all free-phase product. This information is then used to monitor the efficiency and effectiveness of the recovery and overall remediation program. It is difficult to accurately respond to these requests. This difficulty reflects problems associated with determination of product type, true vs. apparent product thickness, and notably, product volume in both passive and active systems. Presented in this paper is a discussion of the difficulties and limitations encountered in estimating volume and recoverability of free-phase liquid hydrocarbon. Also presented are two case histories illustrating the problems associated with volume determinations and their use in monitoring the effectiveness of the free-phase liquid hydrocarbon recovery programs. Not discussed is the migration of petroleum hydrocarbon in the subsurface, which is presented by Schwille (1967), API (1980), Farmer (1983), and Dragun (1988).

Volume Determination Difficulties

Field Measurement Techniques

Free-phase petroleum hydrocarbon in the subsurface is typically delineated and measured by the utilization of ground water monitoring wells. The thickness of free-phase hydrocarbon in a well is typically determined using either a steel tape with water-and-oil-finding paste or commercially available electronic resistivity probes. Either method can provide data with an accuracy to 0.01 of a foot. However, if the free-phase product is emulsified or highly viscous, significant error can result. In addition, measurement using electronic resistivity probes can be misleading if the battery source is weak.

Apparent vs. True Thickness

While monitoring wells have provided some insight as to the extent and general geometry of the pool, as well as the direction of ground water flow, difficulties persist in determining the "true" thickness and, therefore, the volume and ultimately the duration of free-phase recovery and remediation. One difficult aspect of monitoring subsurface hydrocarbons is that accumulations in monitoring wells do not directly correspond to the actual or true thickness in the formation (Blake and Fryberger 1983, Blake and Hall 1984, Hall et al. 1984).

The thickness of free petroleum hydrocarbon as measured in a monitoring well is an apparent thickness rather than a true or formation thickness (Blake and Hall 1984, Hall, et al. 1984). The difference between true and apparent thickness has been attributed to the capillary fringe. The capillary fringe height is dependent upon the grain size distribution as summarized in Table 1 (Bear 1979). Coarse-grained formations contain large pore spaces that greatly reduce the height of the capillary rise. Fine-grained formations have much smaller pore spaces, which allow a higher capillary height.

Because hydrocarbon and water are immiscible fluids, the free-phase hydrocarbon is perched on the capillary fringe above the actual water table. The typical physical relationship that exists is illustrated in Figure 1.

Because the free hydrocarbon occurs within and above the water capillary fringe, once the monitoring well penetrates and destroys this capillary fringe, hydrocarbon migrates into the well bore. The free water surface that stabilizes in the well will be lower than the top of the surrounding capillary fringe in the formation, thus, hydrocarbons will flow into the well from this elevated position. Free hydrocarbons will continue to flow into the well and depress the water surface until a density equilibrium is established. To maintain equilibrium, the weight of the column of hydrocarbon will depress the water level in the well bore. Therefore, a greater apparent thickness is measured than actually exists in the formation.

TABLE 1
General Capillary Rise for Certain Soil Types

Soil Type	Capillary Rise (inches)
Coarse sand	¾ - 2
Sand	4 - 14
Fine sand	14 - 27
Silt	27 - 59
Clay	78 - 160+

The measured or "apparent" hydrocarbon thickness is not only dependent upon the capillary fringe but also on the actual hydrocarbon thickness in the formation. Thus, the measured or apparent hydrocarbon thickness is greater for fine-grained formations and less for coarser grained formations; in the latter, the measured thickness may be more representative of the true thickness. In areas of relatively thin hydrocarbon accumulations, the error between the apparent well thickness and the actual formation thickness can be more pronounced than in areas of thicker accumulations. The larger error reflects the relative difference between the thin layer of hydrocarbon in the formation and the height it is perched above the water table. The perched height is constant for thick and thin accumulations; however, a thick accumulation can depress and even destroy the capillary fringe. The relative difference between apparent and true hydrocarbon thickness increases with decreasing formation grain size and increasing specific gravity of hydrocarbon (Hall et al. 1984).

The thickness measured in a monitoring well with free-phase hydrocarbon situated on a perched layer at some elevation above the water table, can produce even

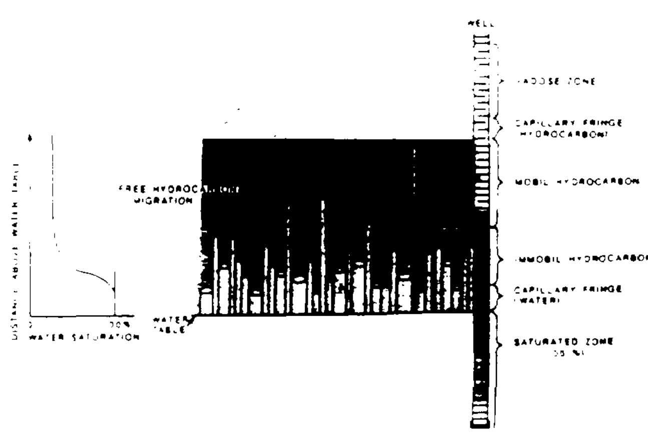

Figure 1. Apparent hydrocarbon thickness in a well and adjacent formation.

larger associated thickness error. This commonly occurs when the well penetrates the perched layer and is screened from the perching layer to the water table. The hydrocarbon then flows into the well from the higher or perched elevation. The accumulated apparent thickness is a direct result of the difference of their respective heights. If a situation such as this exists, a greater error or difference and weight of the column of hydrocarbon should be accounted for in determining true thickness.

Additionally, fluctuations in the water table due to recovery operations or seasonal variations have a direct effect upon the apparent or measured petroleum hydrocarbon thickness (Yaniga 1984). As the water table elevation declines gradually due, for example, to seasonal variations, an exaggerated apparent thickness occurs, reflecting the additional petroleum hydrocarbon that accumulated in the monitoring well. The same is true for an area undergoing a hydrocarbon recovery operation. Where the ground water elevation is lowered through pumping, thicker apparent thicknesses may be observed.

The reverse of this effect has also been documented at recovery sites. When sufficient recharge to the ground water system through seasonal precipitation events or cessation of recovery well pumping occurs with the water table at a slightly higher elevation, thinner petroleum hydrocarbon thicknesses may be observed (Yaniga 1984). During this situation a compression of the capillary zone occurs, lessening the elevation difference between the free water table and the petroleum hydrocarbon, which reduces the apparent thickness.

Empirical Approach to Estimate Volume

Prior to initiation of a free hydrocarbon recovery strategy, the total product and recoverable product volume is estimated. This estimate is dependent on the determination of true product thickness, which can be derived empirically or in conjunction with bail-down testing field methods. Initially, the measurement of apparent free hydrocarbon thicknesses in monitoring wells is conducted. The data generated are then used to develop an apparent hydrocarbon thickness contour (isopach) map. Once developed, planimetering is performed to derive the areal coverage of incremental apparent free hydrocarbon thicknesses. The greater the coverage and number of data points (monitoring wells), the smaller the chosen increment for planimetering. Although apparent thicknesses can vary between monitoring points depending on the thickness of the capillary fringe, calculated thickness values between monitoring points are approximated. Thus, the capillary fringe, and hence the apparent thickness, is assumed to be constant between monitoring points. Upon completion of planimetering, the volume of soil encompassed by the free-phase hydrocarbon pool is estimated. This value is then multiplied by an "assumed" porosity value, based on soil types encountered during the subsurface characterization process to calculate the total apparent volume of product present.

A correction factor is then applied for capillary fringe effects. This factor is empirically derived, reflecting the corrected depth to water as shown below

- CDTW = Static DTP (PT x G)
- Capillary Fringe = (CDTW DTP) APT where,

CDTW = Corrected Depth to Water
DTP = Depth to Product
PT = Product Thickness
G = Specific Gravity
APT = Apparent Product Thickness

Calculation of total apparent volume does not, however, take into consideration the specific yield of the formation. Specific yield is the percentage of the mobile free hydrocarbon that will drain and be recovered under the influence of gravity. This value is dependent on flow characteristics of the hydrocarbon as well as the formation geologic characteristics. Typical values may range from 5 to 20 percent. The total apparent volume is multiplied by an assumed specific yield for the particular area to obtain the volume of recoverable hydrocarbons:

Recoverable Hydrocarbon = Sy x V
Where, Sy = Specific Yield
V = Total Apparent Volume

Field Approach to Estimate Volume

In lieu of using an empirical approach as previously discussed, total apparent volume can be calculated using true product thickness values derived from bail-down testing. **Bail-down testing is a widely used field method to evaluate the true thickness of free petroleum hydrocarbon product in a monitoring well.** Bail-down testing was originally used as a field check method to determine potential locations for free hydrocarbon recovery wells. All monitoring wells at a site that had a measurable thickness of free product hydrocarbon were typically tested. Whether or not all the free hydrocarbon product could be removed from the well and the volume of product bailed were general indicators of areas for "potentially good" recovery.

Bail-down testing field procedures are similar to those performed for in situ permeability tests and involve the measuring of the initial apparent thickness in the monitoring well by an oil-water interface gauging probe. Only free-standing product is then bailed from the well until all of the product is removed or no further reduction in thickness can be achieved. Measured over time are levels of both depth to product (DTP) and depth to water (DTW). Typically, the time increments for measurement follow the same sequence as monitored during an aquifer pumping test. The test is considered complete when the well levels have stabilized for three consecutive readings or if a significant amount of time has elapsed and the levels have reached 90 percent of the original measurements.

If the apparent product thickness is greater than actual product thickness, and the product thickness in the well has been reduced to less than true during bailing, then at some point during fluid recovery the apparent product thickness equals the true thickness (Gruszczenski 1987). During recovery of fluid levels in the well, the top of product in the well rises to its original level. However, the top of water (product water interface) initially rises and then falls. The fall is due to displacement of water in the well reflecting an over accumulation of product on the water surface. The point at which the depth-to-water graph changes from a positive to negative slope is referred to as the "inflection point." At the inflection point, the measured product thickness is interpreted to equal the true product thickness.

Bail-down tests involve the estimation of true product thickness via the graphical presentation of depth-to-product, depth-to-water, and product thickness vs. time as measured during the fluid recovery period in each well (Figure 2).

An "inflection point time," corresponding to the inflection point on the depth-to-water graph, is determined, from which the true product thickness can be estimated on a graph showing product thickness vs. time. Two basic curves have been described (Gruszczenski 1987): type one curves reflect wells with product accumulation less than several inches while type two curves reflect product accumulation greater than 12 inches. The latter indicates an inflection point prior to stabilization of product and water levels and has been reported by Gruszczenski (1987) to indicate a 70 to 95 percent reduction between the apparent and actual product thickness.

When bail-down tests results do not conform to the theoretical response anticipated, maximum theoretical values can be determined by subtracting the static depth-to-product from the corrected depth-to-water. Thicknesses provided in this manner are conservative in that true product thicknesses must be less than or equal to these values, and thus, overestimates the actual product thickness by an amount equal to the thickness of the capillary zone.

Although bail-down testing is a relatively simple field procedure, the analysis and evaluation of the data is speculative. The method contains a number of steps in which errors can easily be introduced. Bail-down testing results are relied upon to determine true thickness in a monitoring well. This is an initial step and basis for calculating a volume and subsequently a recoverable volume of petroleum hydrocarbon. However, some of the areas in which error(s) can easily be introduced include:

- Accuracy of the measuring device used for the initial gauging and recovery of the levels after bailing
- Operator error in measuring and recording levels with time
- Inability of operator to collect early recovery data due to rapid rising fluid levels
- Bailing ground water in addition to product from a low yielding formation
- Lack of a theoretical response or inflection point due to an inordinant length of time for water recovery
- Variable accumulation rates of product caused by borehole effects
- Evaluation of type curves and selection of an inflection point.

If bail-down testing has innate corresponding errors within itself, these errors can only be further compounded

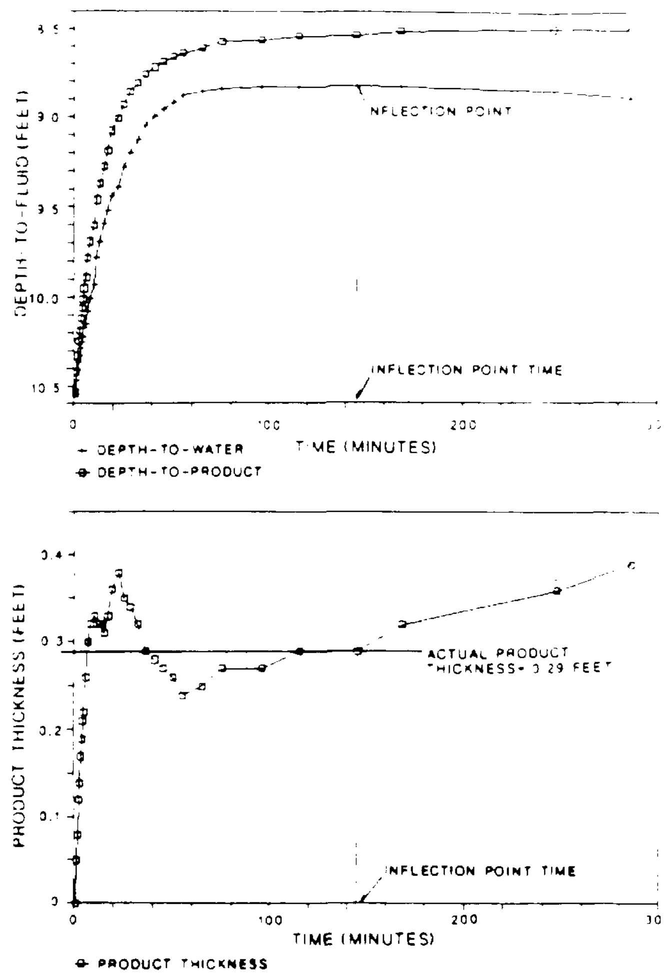

Figure 2. Representative bail-down testing curve results.

because the remaining calculations, extrapolations, and evaluations are based upon this initial step. Although discussion of the validity of bail-down testing to determine true thickness is beyond the scope of this paper, this **procedure remains essentially unproven**. However, this method can be used as a useful supportive tool in comparing the true product thickness data generated from bail-down testing to those derived empirically, thus, resulting in a range for total free-product volume present and a subsequent estimate of recoverable amounts.

Recoverability of Free-Phase Petroleum Hydrocarbon

Relative Permeability

The potential for recovery of free hydrocarbons is governed by the viscosity, density, and true saturated thickness of the hydrocarbon in the formation, the residual water saturation, and the permeability of the formation. These factors determine the relative permeability of the formation to the hydrocarbon. The relative permeability is a measure of the relative ability of free hydrocarbon and water to migrate through the formation as compared to a single fluid. It is expressed as a fraction or percentage of the permeability in a single fluid system. Relative permeability must be determined experimentally for each formation material and each combination of fluid saturations and fluid properties. During hydrocarbon recovery, their ratios are constantly changing. Graphs of relative permeability are generally similar in pattern to that shown in Figure 3.

Some residual water remains in the pore spaces, but as Figure 3 illustrates, water does not begin to flow through the example material until its water saturation reaches 20 percent or above. Water at the low saturation as interstitial or "pore" water, held by capillary forces, preferentially wets the material and fills the finer pores. As water saturation increases from 5 to 20 percent, hydrocarbon saturation decreases from 95 to 80 percent where, to this point, the formation permits only hydrocarbon to flow, not water. Where the curves cross (at a saturation of 56 percent for water and 44 percent for hydrocarbon) the relative permeability is the same for both fluids. Both fluids flow, but at a level of less than 30 percent of what each fluid's flow would be at 100 percent saturation. As the water saturation increases, the water flows more freely and hydrocarbon flow decreases. When hydrocarbon saturation approaches 10 percent, the hydrocarbon becomes immobile, allowing only water to flow. For the example given, the hydrocarbon residual saturation is 10 percent pore saturation limited by the fluid density and viscosity and the formation permeability.

The relations shown in Figure 5 have a wide application to problems of fluid flow through permeable material. One of the most important applications for recovery of petroleum is that there must be at least 5 to 10 percent saturation with the non-wetting fluid and 20 to 40 percent saturation with the wetting fluid before flow occurs. Thus, for oil (the non-wetting fluid), there must be a minimum of 5 to 10 percent saturation of the pore space before the fluid can move through the partially saturated or unsaturated formation and accumulate into pools. Conversely, every oil pool has a quantity of oil that is not mobile, because it is at or below an oil saturation of 5 to 10 percent, and thus is not recoverable.

Residual Hydrocarbon

The recoverability of petroleum hydrocarbon from the subsurface refers to the amount of mobile petroleum hydrocarbon available. Petroleum hydrocarbon that is retained in the unsaturated zone is not typically recoverable by conventional means. Additional amounts of hydrocarbon that are unrecoverable by conventional methods include the immobile hydrocarbons associated with the water table capillary zone. Residual hydrocarbon is pellicular or insular and is retained in the aquifer matrix. In general, as viscosity of the hydrocarbon increases and grain size decreases, the residual saturation increases. Typical residual saturation values for unsaturated, porous soil are presented by Concawe (1979) and tabulated in Table 2.

These values are then multiplied by a correction factor to account for oil viscosity. Correction factors for different product types are:

- 0.5 for low-viscosity products (gasoline)
- 1.0 for kerosene and gas oil
- 2.0 for more viscous oils.

The American Petroleum Institute (1980) has presented some similar guidelines for estimating residual saturation. Basing their work on a "typical" soil with a

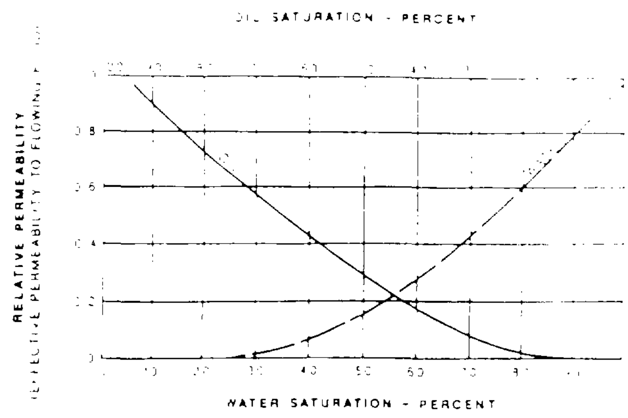

Figure 3. Relative permeability curves for oil and water (after Lavorsen 1967).

porosity of 30 percent, the API gives residual saturation values noted as a percentage of the total porosity of soil as follows:

- 0.18 for light oil and gasoline
- 0.15 for diesel and light fuel oil
- 0.20 for lube and heavy fuel oils.

Similar studies done by Hall, et al. (1984) on hydrocarbon of lower API gravities (i.e., gravities between 34 and 40 degrees) show that specific retention for more viscous hydrocarbons can range between 35 to 50 percent of the pore volume for fine sands with porosities of approximately 30 percent. The loss due to retention in the aquifer as the hydrocarbon migrates to the recovery well can be significant. Wilson and Conrad (1984) claim that residual losses are much higher in the saturated zone (i.e., capillary zone) than in the unsaturated zone.

Comparisons of the estimated volume to the actual volume recovered proves to be the only reasonable procedure for assessing the recoverable volume considering all of the variables involved. These comparisons indicate that the volume of hydrocarbon retained in the aquifer is higher than published residual saturation values. Based on experience for gasoline and low-viscosity hydrocarbons, the recoverable volumes have ranged from 20 to 60 percent of the pore volume in fine to medium sands.

Other Factors

In addition to factors concerning relative permeability and residual hydrocarbon, areal distribution of the pool and site specific physical constraints can have a significant

TABLE 2
Typical Residual Saturation Values for Unsaturated Soil

Soil Type	Oil Retention Capacity (liters/m^3)
Stone, coarse gravel	5
Gravel, coarse sand	8
Coarse sand, medium sand	15
Medium sand, medium sand	25
Fine sand, silt	40

impact upon the degree of recoverability. A relatively small pool in areal extent with concentrated thicknesses is more recoverable, for example, than a thin pool with a large areal distribution. Site-specific physical constraints may have a major impact upon the recoverability of the pool. The problem centers around the difficulty in locating recovery well(s) in their optimum location without conflicting with the facility layout. Furthermore, most recovery programs generate contaminated ground water. Depending on the size of the facility and the scale of the recovery project, the recoverability of product and respective time frame may be limited and highly dependent on the amount of water the facility can handle and the subsequent treatment and disposal options available (Paczkowski et al. 1988).

Case Studies

Case Study A

The site for Case Study A is a 100-acre abandoned petroleum hydrocarbon bulk storage tank farm. This case study is an excellent example of the relationship between the effects of recovery and volume determinations because the site will not have a continual recharge of petroleum hydrocarbon to the existing pool. This case study is also discussed because it presents a scenario whereby the fullest effects of recovery on the total estimated volume and recoverable volume could be readily evaluated.

The site is situated on the Los Angeles Coastal Plain and is underlain by an alluvial sequence of unconsolidated, stratified, laterally discontinuous deposits of sand, silty sand, clayey silt, and silty clay of Recent and Upper Pleistocene age. A thin veneer of recent deposits immediately underlies the site. These deposits are difficult to distinguish from the underlying Upper Pleistocene deposits due to similarities in lithology.

Petroleum hydrocarbons, including gas-oil, were initially stored at the site as early as 1962. The site remained in operation for a period of 15 years and then it was taken out of operation in 1977 when the facility owner discovered losses from storage structures at the site. Initially, six one-pump recovery wells and three monitoring wells were installed by the owner. The systems operated throughout most of 1977 and approximately 38,000 barrels of gas-oil were recovered.

Recovery at the site ceased near the end of 1977, resumed sometime in 1979, and operated intermittently for a period of one year although little gas-oil was recovered during this period.

In late 1982, a consultant was retained to delineate the extent of the free hydrocarbon pool and design and implement a recovery system. Initially, five additional monitoring wells were completed to characterize the subsurface conditions. These additional monitoring wells, in conjunction with the existing wells installed by the owner, were plotted, drafted, and planimetered. Although the lateral extent of the free hydrocarbon pool was not determined, total, available, and recoverable volumes were calculated. These calculations were based upon:

- Measured apparent free hydrocarbon thickness in the well
- Laboratory-derived porosity values from actual soil samples.

Volumetric calculations of total and available free petroleum hydrocarbon for recovery was determined by the empirical method as previously discussed.

A total volume of 476,000 barrels (bbls) was estimated to exist beneath the site; the recoverable volume was estimated to be 200,000 bbls. These estimates were based on the data collected from only 13 monitoring wells.

Two two-pump recovery wells were installed and put into operation in 1983. Additional monitoring wells were installed from 1983 to 1985 to provide further definition of the pool's dimensions. During the latter part of 1983, three additional two-pump recovery wells were installed. By the end of 1985, five recovery wells were in operation and 89 monitoring wells were completed. The additional 76 monitoring wells were installed to refine the initial volume estimates. As of January 1988, 182,000 barrels of gas-oil had been produced from the five recovery wells.

Additional volume calculations were made utilizing the additional monitoring-well data and production totals of existing recovery wells. The initial volumetric determination did not utilize the empirical method but rather straightforward volume determinations based solely on apparent petroleum hydrocarbon thickness, porosity, and expected recovery rates. The second volume calculations accounted for differences in apparent vs. actual thicknesses (Blake and Hall 1984) and exaggerated thicknesses (Hall et al. 1984). The original recoverable volume estimate, based upon 13 monitoring wells, was 200,000 barrels. A revised total volume estimate of 310,000 barrels was calculated based on the additional data generated. Of the total volume, as in the original estimate, 40 percent recoverability was assumed, and thus, 128,000 bbls were determined to be the revised recoverable volume. With a present estimate of 128,000 bbls recoverable and 182,000 bbls recovered to date, the original estimate would have been 310,000 bbls recoverable. Thus, the recovery system has removed about 58 percent of the recoverable product. A summary of the volumetric calculations is presented in Table 3.

TABLE 3
Summary of Volumetric Calculations Case Study A

	Number of Monitoring Wells	Estimated Total (bbls)	Estimated Recoverable Volume (bbls)	Estimated Percent Recovered
Estimate 1	13	476,000	200,000	*
Estimate 2	89	310,000	128,000	58

*Free hydrocarbon recovery not yet initiated.

Additional monitoring wells have increased the coverage of the area and account for greater detail in delineating the petroleum hydrocarbon pool. Thus, new areas of petroleum hydrocarbon accumulations were discovered, resulting in increased volume, reflecting greater detail in coverage rather than from actual changes in hydrocarbon volume.

Case Study B

The site for Case Study B is a relatively large, active refinery with a 125,000 barrel-per-day crude capacity. The site has an extensive tank farm area consisting of several tens of acres and a moderate-sized processing area. The refinery has been in existence for more than 70 years. Continual recharge of petroleum hydrocarbon to the existing plume volume is likely due to the activity and age of the facility. The site is situated on the western edge of the Atlantic Coastal Plain in the Mid-Atlantic region of the United States and is immediately underlain by alluvial deposits comprised of interlayered silty sand and clayey gravel.

A variety of free hydrocarbon products are produced and stored at the facility. The major constituent of the petroleum hydrocarbon pool that underlies the site is fuel oil. The facility's owner had installed a series of monitoring and recovery wells; however, inaccurate production records has made the inclusion of this data into this case study impossible. As of early 1987, 69 existing monitoring wells were measured and volumes calculated by the facility. The volumes were derived in a straightforward method accounting only for the apparent thicknesses measured in monitoring wells. The facility estimated that 141,000 bbls existed. Assuming about 50 percent recoverability, 71,000 bbls of the fuel oil were estimated as being recoverable.

In the latter part of 1987, seven additional monitoring wells were installed, aquifer tests were conducted, and soil samples were collected for porosity determination within the petroleum hydrocarbon horizon. The empirical method to determine total volumes and recoverable volumes was then applied. Based upon data from 76 monitoring wells, which indicated a formation porosity of 20 percent and a specific yield of 0.22, new total and recoverable volume estimates were prepared. About 190,000 bbls of free hydrocarbon product were estimated to be present; assuming 35 percent recoverability, the recoverable volume was estimated at 66,500 bbls.

A two-pump recovery well was put into operation during August of 1987. The recovery well was located in an area of the free hydrocarbon pool of maximum accumulated thickness. Approximately 2500 bbls of fuel oil were produced in four months. In early 1988, all monitoring wells that had an accumulation of petroleum hydrocarbon were bail tested. The raw field data from bail testing was graphed and true thickness values were determined for each monitoring well. The values were plotted, an inflection point selected, and a true thickness evaluated for each monitoring well. The total volume and recoverable volume based upon the true thickness were 67,000 and 20,000 bbls, respectively. A table summarizing total and recoverable volume estimates is presented in Table 4.

Total and recoverable volume estimates were also made from the apparent monitoring well thickness data collected during bail testing. This provided the values of empirical vs. field for direct comparison. The values were 101,000 bbls and 34,5000 bbls for total and recoverable volumes, respectively (Table 4).

TABLE 4
Estimated Total and Recoverable Volumes

Method (Date)	Number of Monitoring Wells	Estimated Total Volume (bbls)	Estimated Recoverable Volume (bbls)
Apparent thickness (Early 1987)	69	141,000	71,000
Empirical (Late 1987)	76	190,000	66,500
Field/bail-testing (Early 1988)	88	67,000	20,000
Empirical (Early 1988)	88	101,000	34,500

Calculations and comparisons were then made between total volume, recoverable volume, and actual production from the area of influence of the recovery well and amount of actual recovered fuel oil. An area of influence contour map for the recovery well was used as an overlay. The overlay was placed on top of three petroleum hydrocarbon thickness maps. Total and recoverable volumes within the area of influence of the recovery well were then calculated. Results of these calculations are presented in Table 5. The estimated recoverable volumes range from 3270 to 11,600 bbls.

TABLE 5
Estimated Volume of Total and Recoverable Free Hydrocarbon Within the Area of Influence

Method (Date)	Estimated Total Volume (bbls)	Estimated Recoverable Volume (bbls)
Empirical apparent thickness 5/87	19,500	5800
Field true thickness 2/88	11,000	3270
Empirical apparent thickness 2/88	38,700	11,600

These estimates were then compared to actual recovery well production volumes. The recovery well produced 4050 bbls from startup to the time at which bail testing was conducted. From the time bail testing was conducted to the end of June 1988 the recovery well had produced 4100 bbls. Estimated recoverable volume based on the field or bail test method (Table 2) was 3270. Therefore, more than 830 bbls were produced in excess of the bail test estimate. The recovery well is still in production and is currently continuing at the same rate of production.

It does seem unlikely that an increase in volume of free hydrocarbon within the area of influence of the recovery well could be on the order of 830 bbls. Although some loss through pipelines and tank bottoms probably occurred, a major loss would have had to occur to provide a volume of this magnitude. Additions to the volume via losses is probable; however, determining the actual contribution from various sources is not feasible.

Summary and Conclusions

Time frames for recovery of free-phase petroleum hydrocarbons are limited by numerous factors or estimates, and are often based on an educated guess. These factors or estimates have innate compounding errors in relation to the following:

- Accuracy of physical measurement where high viscosity and emulsified product are encountered
- Determination of true vs. apparent thickness
- Validity of bail-down tests for estimation of true thickness
- Extrapolation of geologic and hydrogeologic information between monitoring points
- Extrapolation of free hydrocarbon apparent thicknesses between monitoring points
- Averaging of apparent thicknesses for planimetering
- Estimation or assumptions made for key factors including porosity, specific yield, and retention values.

Once an initial estimated volume is determined, pilot testing of a recovery system is initiated to evaluate recovery rates. Factors that significantly affect recovery rates include the areal distribution and geometry of the free petroleum hydrocarbon pool, type(s), and design of recovery system selected, and the performance and efficiency of the system with time.

Volume determinations and subsequent time frame for recovery of free-phase petroleum hydrocarbon can be estimated. However, regulators at all levels need to be aware of the large number of compounding errors associated with these volume determinations. Thus, a reasonable time frame for remediation is clearly an estimate.

The progress of recovery efforts cannot be based confidently on free hydrocarbon thickness maps. Although these maps provide quantification of overall trends, the numerous factors that impact hydrocarbon thicknesses make accurate quantification difficult. Estimates of effectiveness thus are based on barrels recovered to date divided by the total volume of barrels that are considered recoverable. Furthermore, as the recovery project progresses and new data are introduced, the volume and time frame for recovery should be continually reevaluated and revised.

In determining total and recoverable volumes of free hydrocarbon, the factor of recharge to the volume is undeterminable. From experience and the case studies provided, developing a range of total and recoverable volumes is suggested. A valid way to determine this range is a comparison of values generated from the empirical and field (bail test) methods. Also, as additional monitoring well points are incorporated into the project, these new data need to be coupled with existing data and revised estimates made. Finally, comparisons of the estimated recoverable volumes to the actual volume produced proves to be the only reasonable procedure for estimating the recoverable volume considering all the variables involved.

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